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The single European electricity market : A long road to convergence

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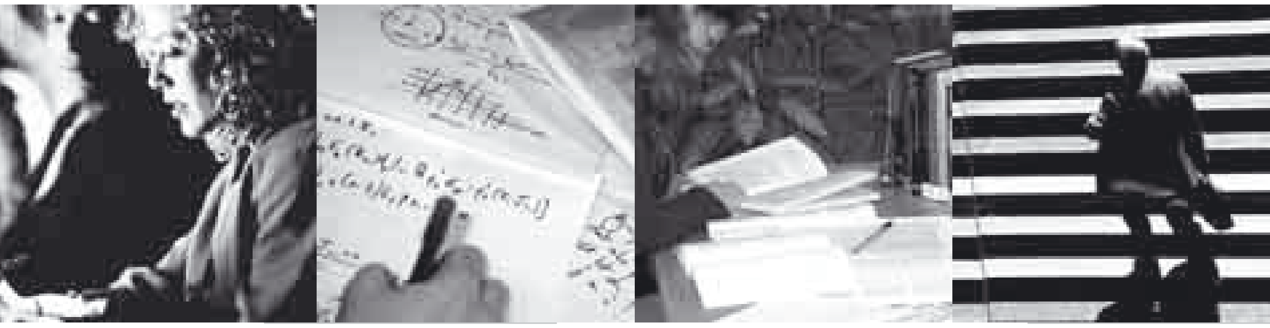

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The single European electricity market:
A long road to convergence

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Abstract

In the context of a first Working Paper the authors argued that electricity has a number of characteristics that set it apart from other commodities. It was demonstrated that some of these characteristics might complicate the deregulation process. This paper analyses the ongoing deregulation process in the European electricity sector and attempts to establish whether these difficulties can more readily be solved at European level. It would appear that some problems, e.g. economies of scale in electricity generation, have less of an impact at European level than within smaller national markets. However, a number of difficulties have to be overcome before a unified European electricity market can become a reality. These include the limited interconnection capacities between Member States. The European Commission has taken steps to improve the situation, for example by offering financial support for investments and promoting the development of regional markets as an interim measure ultimately leading to a fully integrated market. Apart from the difficulties related to electricity generation and transmission there are also exogenous factors that influence the ongoing deregulation process, e.g. the implementation of the Kyoto protocol and the dramatic increases in primary fuel prices.

This paper argues that a consistent, stable and uniform European regulatory framework must be put in place if the impact of these difficulties is to be minimised.

JEL Classification: L94.

Keywords: Electricity deregulation

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1 INTRODUCTION

This is the second Working Paper on the ongoing deregulation process of the electricity sector in Europe.

The first paper[1] compared the electricity sector to the telecommunications sector and stated that, even though there are similarities, the two sectors have some very different characteristics. The authors argued that, due to these differences, a successful deregulation in one sector can in no way be generalised to the other one.

This second paper discusses into more detail the ongoing deregulation process in the European Union.

The deregulation of the European electricity sector was launched on 19 December 1996, the date on which Directive 96/92/EC "concerning common rules for the internal market in electricity" was adopted. It entered into force two months later, on 19 February 1997. According to the European Commission[2], liberalisation aims at increasing efficiency, harmonising and reducing electricity prices, improving public services, cutting reserve production capacities, making a better use of resources, giving customers the right to choose their supplier and providing customers with a better service.

Relying on the experiences of the pioneers - the Scandinavian countries and the United Kingdom - Directive 96/92/EC subdivides the electricity sector into four segments: generation, transmission, distribution and supply[3]. Generation and supply are opened up to competition, whereas transmission and distribution remain monopolistic. The principal requirements of the first Directive are:

– integrated companies must keep separate accounts for transmission, distribution, other electricity-related activities and other (non-electricity-related) activities. This separation of accounts aims at avoiding discrimination, cross-subsidies and distortion of competition;

1 Coppens F. and D. Vivet (2004).
2 See European Commission (1998).
3 For details, see the complete text of Directive 96/92/EC.

- the generation segment should be opened up to competition, either by an authorisation procedure and/or by a tendering procedure[4];

- transmission and distribution remain monopolies. Non-discriminatory rules on access to the transmission and distribution networks should be established. Member States can choose between (a) regulated third party access, (b) negotiated third party access or (c) the single buyer model[5].
  The transmission system should be operated by an independent system operator (the transmission system operator or TSO) responsible for operating, maintaining and developing the network and its interconnections.
  As in the case of the transmission system, an independent system operator (the distribution system operator or DSO) should be designated to operate and manage the distribution network in its area;

- the supply segment is also opened up to competition; "eligible consumers" are free to switch suppliers. Member States can provide their own definition of 'eligible consumer', though they have to meet minimum requirements: by 19 February 1999, 26 p.c. of the total consumption must be eligible; furthermore, companies consuming over 100 GWh per annum are always eligible. By 19 February 2000 this share must be at least 28 p.c. and three years later eligible consumers should represent at least 33 p.c. of total national consumption;

- Member States must also designate a competent and independent authority to settle disputes relating to the contracts and negotiations.

In accordance with the principle of subsidiarity, the Directive aims at laying down general principles to establish a framework and leaves their detailed implementation to the Member States, allowing them to choose the regime which corresponds best to their particular situation.

The preamble to the Directive clearly states that, following implementation of the Directive, some obstacles to trade in electricity will nevertheless persist, and that, therefore, proposals for improving

4 Under an authorisation procedure, any company may build and operate a new electricity-generating plant, provided that it complies with the planning and energy supply criteria for authorisation specified in the Member State in question. Alternatively, under a tendering procedure, whenever there is a necessity for new generating capacity on the basis of regular long-term planning forecasts, an independent body draws up an inventory for new means of production and the requisite capacity is allocated by a tendering procedure.

5 Under a negotiated third party access system, each network user negotiates the terms of access with the system operator. With regulated third party access, the tariffs are set in advance by the relevant authorities, and applied to all users of the network. These tariffs are published. Under the single buyer model, eligible customers apply to a legal entity which is responsible for central electricity purchasing and selling.

the operation of the internal market may be made in the light of experience. As such, it did not come as a surprise when the European Council of Lisbon in March 2000 called for faster liberalisation in the electricity and gas sectors, in order to achieve a fully operational internal market. The main issues identified concerned access to networks, tarification, market power in electricity production and different degrees of market opening between Member States.

Directive 2003/54/EC, repealing Directive 96/92/EC, was therefore adopted on 26 June 2003. The main new features provided by this new Directive can be summarised as follows[6]:

- the timetable for market opening was extended to households. From 1 January 2004 onwards, all non-households must be free to choose their supplier and three years later all consumers should be eligible;
- as far as unbundling is concerned, the second Directive requires legal unbundling as well as management unbundling for network operators (i.e. TSOs and DSOs);
- non-discriminatory access to the transmission and distribution networks is based on ex ante fixed access tariffs (i.e. regulated third party access);
- as far as generation is concerned, new capacity should be developed through an authorisation procedure. This can be extended by a tendering procedure when security of supply is at risk;
- provisions regarding public service obligations (universal service), environmental protection and security of supply are included in the new Directive. Member States' responsibility relating to security of supply can be delegated to the regulator;
- an extension of the regulator's task (e.g. fixing rules for the use of the interconnection capacity, supervision of network access tariffs, overseeing the level of transparency and competition, etc.).

Besides these core Directives, the European Commission has also adopted a number of other measures, in particular in regard to the environment and cross-border exchanges, which will be discussed below.

Summing up, the electricity sector consists of

- Generators
- Transmission system operators; to be split up into
    - network development and maintenance (including interconnections)
    - network operation; supply-demand equilibrium, congestion, losses, etc.
- Distribution system operators

[6] For details, see the complete text of Directive 2003/54/EC.

– Suppliers

– An independent regulator
– A market mechanism

In the first section, the concept of unbundling will be treated. The next section handles several points related to electricity generation. Power transmission is the subject of the third section. Taking a European perspective, distribution will not be touched upon while for transmission the cross-border flows will be emphasised. Cross border congestion management often makes use of power exchanges, as such this topic is also handled in the third section. The final chapter is about regulation.

2 UNBUNDLING

As stressed in the preceding paragraph, one of the main changes introduced by the Directives is the requirement to unbundle the vertically integrated sector into four segments, i.e. generation, transmission, distribution and supply. The rationale is that, unlike generation and supply, transmission and distribution are natural monopolies (with network externalities) where, by definition, competition cannot be introduced. Consequently, since competitors in generation and supply need access to the networks, the electricity Directives have provided the separation of competitive from non-competitive segments, in order to avoid discriminatory access and conflicts of interest.

Unbundling implies that decisions previously taken within the scope of one firm should now result from market mechanisms. Economic theory holds that, while the introduction of competition in some subsegments (generation and supply) might create a downward pressure on prices, the increased interaction and the need for coordination among participants from different segments could raise transaction costs. Whether the overall result will lead to lower or higher prices depends on the relative size of the two phenomena[7].

The promoters of electricity deregulation implicitly assume that the downward pressure on prices resulting from competition (in generation and supply) will largely compensate for transaction costs (resulting from interactions between generation, transmission, distribution and supply). It is nevertheless important to note that, if the transaction costs resulting from unbundling are high, the overall costs can be reduced by re-integrating, and the pursuit of cost-optimality would generate attracting forces among the various segments[8]. In that case, problems would arise when these unifying forces relate to a (monopolistic) network segment because this might result in a tendency toward a re-integrated monopolistic industry.

Although difficult to measure, the transaction costs resulting from the separation of network segments from the other segments could be substantial in the case of the electricity sector. This is mainly due to the continuous need for coordination among the segments and the ensuing necessity of information exchange[9]. When these transaction costs are high, countervailing forces - i.e. regulation - will be needed to avoid re-integration.

European legislation requires network segments to be legally separated from competitive segments. While the principle of unbundling is simple in theory, it can assume a number of forms, allowing

7 In this respect, see Joskow P. (2002) and Coppens F. and D. Vivet (2004).
8 This mechanism is similar to the cost reduction that results from integration in the case of the existence of economies of scale.
9 See e.g. Coppens F., D. Vivet (2005).

different degrees of independence between the unbundled segments. The first Directive essentially requested a separation of accounts. This was quickly considered to be insufficient, so that the second Directive strengthened the requirements, imposing a legal separation and minimum criteria aimed at ensuring organisation and decision-making independence[10]. In most Member States, the TSO (or TSOs in the case of Germany) today is a legally independent unit. In some cases (e.g. the Netherlands, the UK, the Scandinavian countries, Italy, Portugal and Spain), there even is a strict ownership separation between the TSO and the competitive players; in most of these cases this means that the TSO is state-owned. As far as the DSOs are concerned, the situation is more problematic, since only half of the Member States have legally unbundled DSOs[11].

For the competitive segments - generation and supply - a strict separation between the two activities is not required by the Directive. In fact, the main development over the past couple of years is the substantial wave of acquisitions and mergers that took place throughout Europe[12]. By reinforcing their positions on both the generation and the supply markets, companies hope to be sheltered from market-risk exposure, credit risks and low market liquidity. Suppliers have to buy power at uncertain and volatile prices. At the same time, they often have more or less fixed price contracts with their customers. One way to eliminate the associated price risk is by (re-) integrating with a power producer. Doing so provides the producer with a guaranteed output, implying mutual gains. These re-integration movements reduce risk, and as such might have a positive impact on costs and prices[13] (and as a consequence they are beneficial to consumers). On the other hand there might be a potential for (abuse of) market power. Therefore integration of a producer with a supplier often required the producer to sell so-called Virtual Power Plants or VPPs. In Belgium, for instance, Electrabel was obliged to auction off 1,200 MW of VPPs in exchange for its subsidiary, Electrabel Customer Services, being granted default supplier status. In France, EDF must auction off 6,000 MW in exchange for acquiring joint control in the German energy company EnBW. In the Netherlands Nuon was asked to auction off 900 MW of VPPs after having taken over Reliant's generation capacity. VPPs are explained in box 1. The efficiency of the use of VPP depends on the context[14].

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10 In terms of organization and decision-making independence, the rules introduced by the Directive 2003/54/EC are as follows:

- those persons responsible for the management of the transmission system operator may not participate in company structures of the integrated electricity undertaking responsible, directly or indirectly, for the day-to day operation of the generation, distribution and supply of electricity;

- appropriate measures must be taken to ensure that the professional interests of the persons responsible for the management of the transmission system operator are taken into account in a manner that ensures that they are capable of acting independently;

- the transmission system operator shall have effective decision-making rights, independent from the integrated electricity undertaking, with respect to assets necessary to operate, maintain or develop the network.

11 See Commission of the European Communities (2005b).

12 Codognet et al. (2001) provide an extensive review of features and rationales of these acquisitions and mergers.

13 This type of risk hedging is called a physical hedge. The price risk can also be hedged using derivatives (i.e. a financial hedge). Efficient financial hedging requires organised derivatives markets and as such entails transaction costs.

14 For an example in which VPPs are inefficient, see Coppens F. (2005).

Box 1: Virtual Power Plants

Virtual Power Plants are option contracts. The owner of the contract has the right to buy a certain amount of energy at a price fixed in the contract (the energy price) during a specified period of time in the future (the delivery period). The contract thus fixes the unit price, the quantity and the delivery period.

The price of the contract is fixed at an auction. At the auction, the seller (e.g. EDF, Electrabel) calls a price. All potential buyers enter bids mentioning the amount (in MW) they want to buy at that price. If the total bids entered exceed the total amount offered by the seller, no deals are concluded. The price is increased and a new round starts.

After a number of rounds the price is known, as well as the capacity sold. This price is called the capacity price.

There is a separate auction for base-load VPP and peak-load VPP.

Summing up, a VPP buyer buys a contract for a number of megawatts at a certain price, or to be more precise, he buys the right to use this number of megawatts during a period of time in the future, and for each hour he uses them, he has to pay the energy price (fixed in the contract). The price paid for the contract is called the capacity price.

The VPP contracts thus have a fixed price (the capacity price). That fixed price gives the owner the right to buy electricity at a known price (the energy price) during a predefined period. This means that it is 'as if' he had bought a virtual production plant with a fixed cost equal to the capacity price and a variable cost equal to the energy price, hence the name.

Example based on the Belgian VPP auction

The energy price in the Belgian VPP contract is 12€/MWh for VPP base-load. The fifth VPP auction[15] yields a capacity price of 17,128€/MW/Month.

Thus, for obtaining the right to use 1 MW of capacity during a certain month in the future, the buyer has to pay 17,128€. This does not mean that he actually uses it, since it only gives him the right to do so.

15 See www.endex.nl/vpp/files/vpp_results_5th_auction.pdf, a weighted average price is used.

Assuming that he uses this 1 MW during each hour of the month, this means, since there are 24x30=720 hours in a month, that he pays a fixed price of 23.8€ for each hour he can use that MW, plus an additional price of 12€ (the energy price) when he actually uses it. This results in a total of 35.8€/MWh, assuming he exercises the option for each hour of the month.

For the sake of completeness it should also be mentioned that, due to increased (future) use of gas for power generation, there is also potential for mutual gains from vertical integration between gas and electricity sectors. The production of electricity within such an integrated company reduces the risk associated with the volatility of the primary fuel prices; this volatility is expected to increase in the future. The gas supplier, on the other hand, is guaranteed a future sales volume and reduces the risk of his massive investment costs. In addition, possibilities for price arbitrage are created; the gas can be sold on the spot market or used for electricity generation depending on the most advantageous commodity price[16].

It is pointed out that there is also a rationale for horizontal integration movement. Horizontal integration is motivated both by a search for economies of scale (see chapter 3) and by the desire to acquire a position on the various national markets. In fact, exporting to other countries entails less (balance) price risks when the exporter has generation capacity in the target market (in that case the exporter is not exposed to volatile balancing prices - see also box 3 infra). These cases will be discussed in the next section.

[16] As to the convergence of the gas and electricity sectors, see for example Chauvet N. (2000).

3 ELECTRICITY GENERATION IN EUROPE

3.1 *Heterogeneous production facilities*

Table 1 details net electricity generation by primary energy source for some European countries and for the EU as a whole. On the whole, conventional thermal sources (coal, gas and oil) are the most widely used (55 pct. of electricity generated in EU 25), followed by nuclear energy (31 p.c.) and hydropower (11 p.c.), while other renewables (wind and solar energy only) account for hardly 3 p.c.

Despite the overall dominance of conventional thermal sources, the main point revealed by the table is the diversity in the primary fuel mix across European countries. For example, nuclear energy is not used in Austria, Italy and Norway, whereas it is the major source in France, Belgium and Sweden. As far as hydro power is concerned, table 1 shows that, while being a minor source of electricity in most countries, it is very intensively used in Norway, Austria and Sweden. A last example referred to is the Netherlands, where conventional thermal energy is far more dominant than in the rest of Europe.

TABLE 1 Net electricity generation by primary energy source in Europe (2003)

	Total net electricity generation (TWh)	Breakdown by primary energy source (percentages)			
		Nuclear	Conventional thermal	Hydro power	Other renewables
EU25	2,944.6	31.4	54.8	10.5	2.9
EU15	2,616.9	32.7	52.8	11.3	3.3
Austria	57.5	0.0	40.7	57.9	1.4
Belgium	80.4	56.0	41.2	1.6	1.2
France	541.6	77.7	10.0	11.8	0.6
Germany	560.1	27.9	63.2	4.4	4.5
Italy	279.0	0.0	80.6	15.7	3.8
Spain	251.4	23.6	53.3	17.1	6.0
Sweden	132.5	49.4	10.2	40.0	0.8
United Kingdom	375.0	21.9	75.5	0.8	1.9
The Netherlands	93.2	4.1	92.0	0.1	3.9
Norway	106.1	0.0	0.7	99.0	0.4

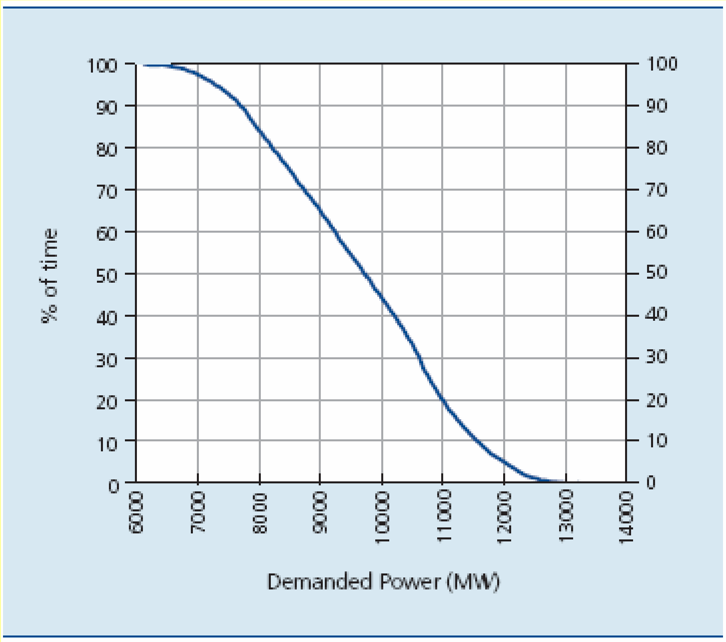
Source: Eurelectric

The use of various primary fuels for power generation is justified from a cost perspective (see box 2). However the different choices of primary fuel mixes across countries is the result of past national choices based on a combination of economic, geographical, geopolitical and/or political considerations. An example of geographical considerations is provided by Austria, where, for topographical reasons, the Alpine regions and the flow of the Danube river allowed extensive use of hydro power stations. As far as geopolitical considerations are concerned, the case of the Netherlands is explicit. Since that country is an important natural gas producer, it is not surprising that about 70 p.c. of its electricity is produced from gas, as a way to ensure security of supply. Finally, the decision whether or not to use nuclear energy, and the sometimes endless debates over it, is often based on (geo-) political considerations. The reason for stressing this diversity in fuel mixes and arguments underlying it is that is has important consequences in a liberalised generation market. This is the subject of the two following sections.

Box 2 Electricity economics

The economics of electricity and the economically optimal production park will be illustrated using the Belgian load duration curve (see graph 1).

GRAPH 1 LOAD DURATION CURVE FOR BELGIUM



Source: ELIA

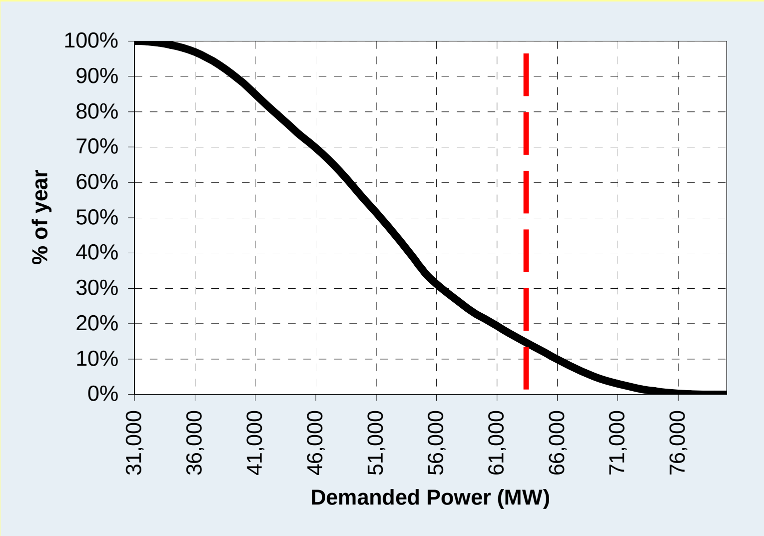
This curve presents the volatility in power demand in the course of a year. It shows that throughout the year (see 100 p.c. on the vertical axis) a capacity of 6,000 MW is needed. A capacity of around 9,200 MW is needed for 60 p.c. of the year. During a very small part of the year (5 p.c.), more than 12,000 MW is necessary.

In order to decide on the optimum production facilities in economic terms, these findings should be compared with the production costs. Graph 3A infra shows that nuclear stations are most efficient, if they run at least 5,300 hours per year, i.e. more than 60 p.c. of the year. They are followed by coal-fired stations which are most efficient, if they run for more than 39 p.c. of the year. Below 39 p.c., gas-fired stations should be used.

Since nuclear plants are beneficial when they run at least for 60 p.c. of the year, and because more than 9 GW is needed during the same part of the year, it can be concluded that - on purely economic grounds - there is a potential for 9 GW of nuclear capacity. By a similar reasoning there is a need for 1.2 GW of coal-fired stations and for 3 GW of gas-fired stations (for the sake of simplicity, only nuclear, coal and gas power stations were considered). Belgian power generation capacity consists of 5.7 GW of nuclear power, 1.4 GW of hydro power and 8.3 GW of conventional thermal power (European Commission (2004)).

Applying the same reasoning to the French load curve (see graph 2), it seems that the cost-optimal nuclear capacity for France would be somewhere between 46 GW and 50 GW of nuclear power. Compared to the 63 GW of installed French nuclear capacity, it is shown that France has a nuclear over-capacity and that it can decrease production costs by exporting nuclear power. Indeed, the French nuclear capacity is sufficient for 85 p.c. of the year. From a cost perspective, nuclear production during 60 p.c. of a year is optimal. Average production costs can therefore be reduced by producing more, as can be seen in graph 3.

GRAPH 2 LOAD DURATION CURVE FOR FRANCE



The French production capacity consists of 63.3 GW of nuclear power, 27.3 GW of conventional thermal power and 17.9 GW of hydro power (European Commission (2004)).

3.1.1 Generation costs

As explained in Coppens F. and D. Vivet (2004) the specific characteristics of an electricity system (the permanent equilibrium between supply and demand) together with a volatile and inelastic demand require important reserve capacities and the existence of sub-segments in the generation market (see also box 2). A base-load plant is running most of the year and is characterised by high fixed costs and low variable costs. Nuclear power plants and (accumulation) hydro plants are typical examples. Graph 3 shows that the costs of nuclear power plants are around 24 €/MWh (running 8000 h/year). The high fixed costs of this type of plants imply the necessity for high capacity factors[17]. Peak-load plants, on the contrary, show low fixed costs and higher variable costs. By definition it has low capacity factors. Average production costs of a CCGT[18] are 43 €/MWh (running 3,000 h, see graph 3A). For coal-fired production the average costs amount to 34 €/MWh (5,000 h).

The optimal size of nuclear plants (1 GW to 1.5 GW) is quite high compared to e.g. a CCGT (350 MW to 450 MW). Proponents of competitive electricity generation markets often argue that scale effects have disappeared with the introduction of the CCGT and that, as a consequence, competition can be introduced in electricity generation.

Their reasoning can be illustrated by two (fictitious) examples, one for a country with a small base-load (e.g. 5 GW) and another for a country with a relatively high base-load (e.g. 50 GW). When nuclear plants are used in the small market, there is a potential for at most 5 nuclear reactors (i.e. the size of the base-load market, 5 GW, divided by the optimal size of one reactor, 1 GW). Using CCGT generation instead of nuclear plants, there is a potential for 13 CCGT units (using an optimal size of 400 MW). The potential number of units in the high base-load market is computed in a similar way. The results are 50 units when nuclear technology is used and 125 units when use is made of combined cycles.

It is obvious that the number of units computed as 'market size divided by optimal plant size' is a theoretical maximum of competitors. Indeed, advantages related to knowledge- and site-sharing will probably result in the grouping of units resulting in there being less competing companies.

This simple example clearly illustrates that the potential degree of competition depends on the relative importance of two factors; (a) the market size and (b) the optimal plant size. It also shows that - depending on the technology chosen - an oligopoly might be the optimal solution for modest markets and that the introduction of competition necessitates a broader context than the national market. In other words, integration with neighbouring countries is needed, just as well as sufficient interconnection capacities. Uniform legislation within this broader market is the second condition in order to create the same level playing field for all competitors.

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17 The capacity factor is the effective annual production divided by the maximum possible annual production.

18 CCGT = Combined Cycle Gas Turbine.

Striving for a larger market in order to enhance competition is an explicit goal of the European Commission: "*The Community is seeking to create a competitive market for electricity for an enlarged European Union, not only where customers have choice of supplier, but also where all unnecessary impediments to cross-border exchanges are removed. Electricity should, as far as possible, flow between Member States as easily as it currently flows within Member States*".[19]

Assuming that a base-load plant is running throughout the year (e.g. 8000 hours), it follows from graph 3A that the generation costs come to 24 €/MWh for a nuclear plant and to 32 €/MWh for a CCGT. The total annual production cost to meet the base-load is computed by multiplying these costs by the number of hours (8760) and the required number of megawatts (i.e. the market size). Base-load generation costs amount to 1,051 million euro for nuclear generation and to 1,402 million euro for CCGT in the small (5 GW) market. Costs are ten times higher in the larger (50 GW) market.

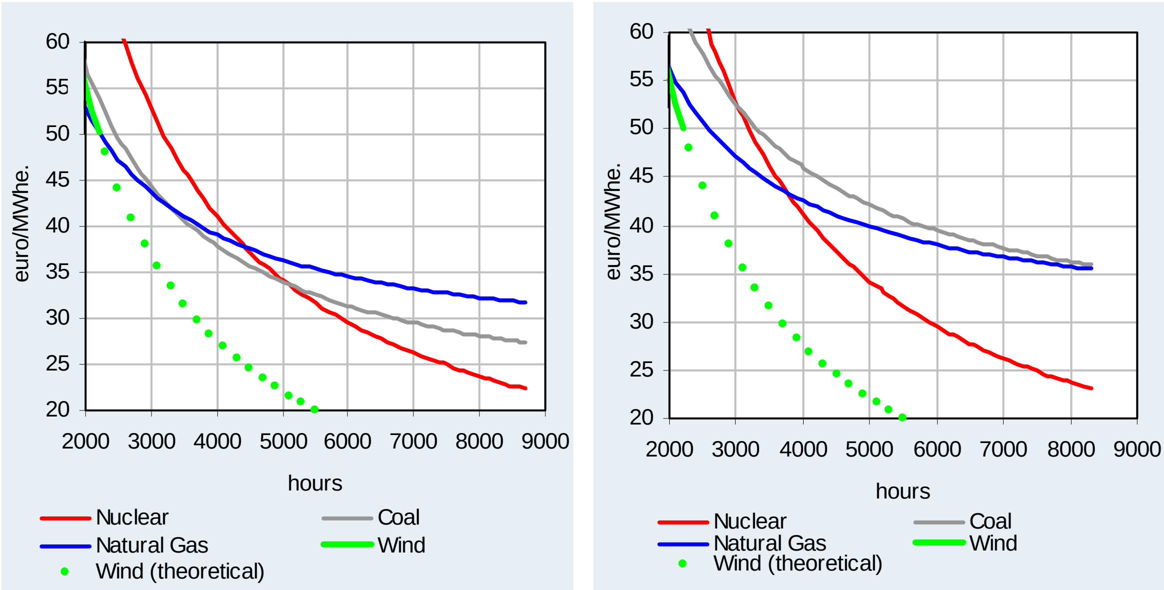
Meeting base-load demand using the smaller sized CCGT allows more generators and as a consequence will (potentially) lead to more competition. From a cost perspective point of view (at the current state of technology) nuclear production seems cheaper. However, lower production costs do not necessarily imply a lower price. This conceptual difference gives rise to so-called infra-marginal rents which are the subject of the next paragraph.

The foregoing reasoning does not change fundamentally when the environmental effects are taken into account. Graph 3B adds 10 €/tCO_2 to the production costs of the different plant types. Including the cost of environmental externalities increases the generation costs for the fossil power plants. Moreover, it changes the dispatch order (see graph 3B). CO_2 emissions are negligible for nuclear plants; as a consequence, these additional costs do not affect their production costs. Emissions are higher for coal-based power productions than for power produced from gas. This implies that CCGTs have lower production costs (than coal-fired plants), when CO_2 emissions are taken into account.

[19] See European Commission (2004b) p. 3.

GRAPH 3 AVERAGE PRODUCTION COSTS OF ELECTRICITY-GENERATING STATIONS

A. Excluding the costs of CO_2 emissions **B. Including the costs of CO_2 emissions**



Source: Coppens F. and D. Vivet (2004), based on data for Finland.

3.1.2 Inframarginal rents

The volatile and inelastic electricity demand, combined with the non-storability of electric power, necessitates a heterogeneous production park (see also box 2). This heterogeneity in its turn implies a stepwise production function. Making abstraction of plant maintenance, this production function can be assumed to be the same at each hour of the year. In competitive markets the electricity price is determined as the intersection between supply and demand. Demand is however very volatile and inelastic so that the demand function is changing continuously.

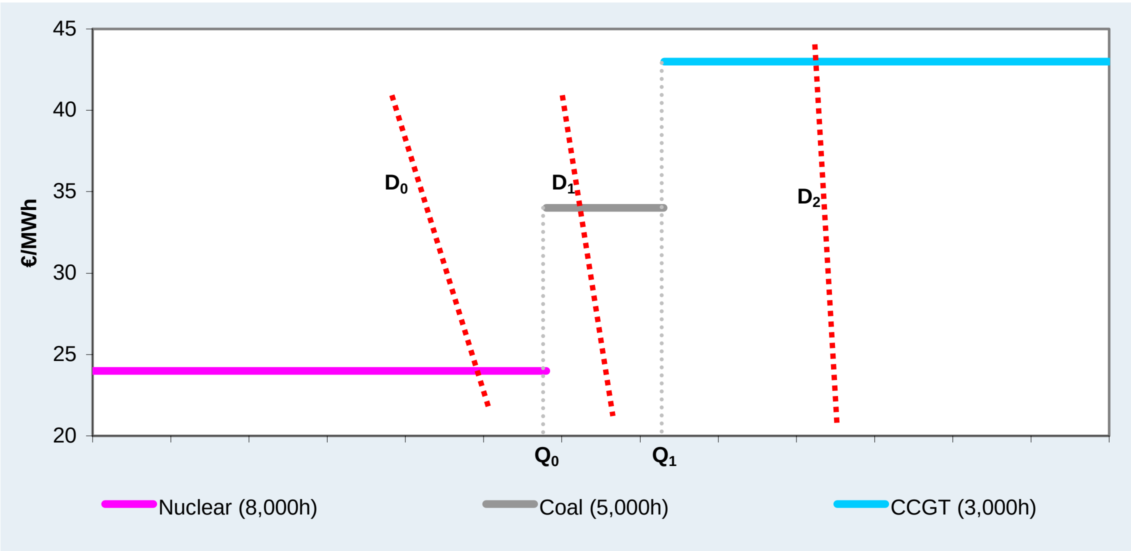
Graph 4 shows the cost structure of a (fictitious) electricity production system with nuclear, coal-fired and gas-fired power stations together with demand curves (D_0, D_1, D_2) at different moments (a base-load, mid-peak load and peak-load moment). The supply curve is based on the cost data in graph 3A. For power stations running 8,000h per year, nuclear capacity costs 24 €/MWh on average, coal 34 €/MWh (when running 5,000 h) and gas 32 €/MWh (when running 3,000 h). Capacities are indicated on the horizontal axis.

If (volatile) demand is low, e.g. at level D_0, then the cheapest capacity (nuclear in the example) is sufficient to meet demand and the market price will equal the lowest production costs. If during another hour of the year demand shifts to a level D_1, the nuclear capacity is no longer sufficient and at least one coal station will be needed. This coal station is called the marginal production unit, and this marginal unit determines the market price. As a consequence, the market price is higher than the production costs of the cheapest technology and (each megawatt of) the cheapest technology earns a rent of (34-24)€ during each hour that demand is between Q_0 and Q_1. This rent is called an inframarginal rent.

The inframarginal rent is even higher when demand increases to level D_2. In that case, the marginal unit is a CCGT and the market price is driven by the production cost of this type of technology (43 €/MWh in graph 4). The infra-marginal rent on nuclear power is computed as (43-24) x number of Megawatts of nuclear power x number of hours that each megawatt is used. If the capacity of the cheapest technology is low compared to the required base-load capacity, the number of hours will be high and these rents can be quite substantial[20].

Note that at a demand level D_2 coal fired stations also earn a rent (43-34)€/MWh.

GRAPH 4 ELECTRICITY PRODUCTION SYSTEM



Due to the intraday demand volatility, most electricity markets divide a day into subperiods (e.g. hours or even quarters of an hour). The various subperiods should be seen as different markets (i.e. a market for each hour of the day) and the cheapest technology can participate in all markets (during hours of high demand as well as during hours of low demand), contrary to the more expensive technologies that can only generate a positive revenue in the high demand hours (markets). This implies that in peak-demand hours a mixture of technologies is used, whereas the output of these technologies is indistinguishable. In each period, all technologies, except the most expensive one, earns an infra- marginal rent. Thus a generator disposing of a portfolio of generation technologies has an advantage over one that has only a limited technology choice (i.e. not including the one with the lowest production costs), especially if the portfolio of the former includes the cheaper technology.

20 For an illustrative numerical example, see e.g. Coppens F. (2005).

The possessors of the cheaper technology thus earn a profit above normal in the form of inframarginal rents. In a competitive market these rents are not a problem in themselves. Indeed, when these margins become too high, competitors will be attracted and more electricity will be generated using the cheaper capacity. Free entry is thus a necessary condition.

Newcomers in the base-load segment have two options: constructing new capacity or importing cheap power from abroad (in both cases the supply curve is shifted to the right in graph 4). As far as new capacity is concerned, the cheapest production technologies seem to be hydro power and nuclear power. In hydro power, entry is limited by physical constraints. Nuclear power is a very sensitive issue today and new plants are actually forbidden in some countries. This implies that owners of such capacity are protected by (physical or legal) entry barriers. The second option, i.e. import from neighbouring countries, is also problematic; limited interconnector capacity becomes the main problem.
Moreover the cheapest generation technologies happen to be very capital-intensive. This creates an additional financial entry barrier because only companies having the potential to finance these huge investments are potential entrants. It is clear that companies profiting from infra-marginal rents have an advantage from this point of view.

As a consequence, there are (physical, legal, financial) entry barriers that could be an obstacle to a well-functioning competitive (even to a contestable) market.

It is also observed that the inframarginal rents earned on low emission plants increase when greenhouse gas emissions costs are internalised for the other technologies. They also increase when the production costs of other technologies increase (e.g. due to an increase in primary fuel prices).

The inframarginal rents can be reduced by expanding the cheaper technology[21] (shifting the supply curve to the right in graph 4) and in that case lower prices could result.

As for the optimal plant size and economies of scale, the existence of inframarginal rents is to be considered relative to the relevant market. If one considers the national market to be relevant, the heterogeneous production park must also be seen in this context. An example in this respect is the Belgian national market where - when seen in isolation - nuclear capacity (5.7 GW) is insufficient to meet minimum load (6 GW, see graph 1). This gives rise to inframarginal rents. These rents result in biased market power measures like e.g. the Lerner index[22].

[21] It is also pointed out that, according to the reasoning in box 2, there is an upper limit beyond which expansion becomes economically inefficient.
[22] See e.g. Coppens F. (2005).

3.2 Main players

The electricity landscape in Europe is today dominated by less than ten companies, the main ones of which are Électricité de France (EDF), E.ON (Germany), RWE (Germany), Enel (Italy), Endesa (Spain), Vattenfall (Sweden) and Electrabel (Belgium). More than two-thirds of the European production is now controlled by these companies, with 50 p.c. by the first four[23]. It should be noted that EDF, with a production of just over 480 TWh per year (in 2005), is far ahead of its nearest rivals, E.ON and RWE, which each represent less than 230 TWh per year (in 2005). It may be said that EDF's lead, while resulting from an expansionist and ambitious strategy, is merely due to the fact that historically France has had only one major electricity company, unlike the other large European countries, where the sector was divided among several enterprises. In fact, the structure of competition today is largely the result of historical and political choices, in particular the decision whether or not to favour a so-called national 'champion'.

In this respect, it may be held that the European Directive does not go far enough by leaving the Member States too much freedom. In particular, the Directive makes excessive use of the well-known subsidiarity principle, whereby the European Union does not take action unless it is more effective than action taken at national, regional or local level. The result is that the Directive does not give precise instructions as to the organisation of the generation market (or other segments of the electricity sector), leaving the door open to variations in national implementing provisions. More generally, as underlined by Boisseleau F. and R. Hakvoort (2003), "The restructuring process has focused on legal and organisational issues, but did not contain specific prescriptions for economic design of the market". This situation is essentially due to the fact that the Directive is a compromise reached between several and sometimes opposing parties concerned. Moreover, these disparities are naturally reinforced by the diversity of systems which prevailed before the deregulation, in particular as far as the structure of ownership or the degree of vertical integration are concerned[24].

3.3 Concentration on national markets

Due to the limited interconnection capacities, the relevant market is sometimes defined as the national market, and concentration measures are often computed with respect to the size of the domestic market. It is questionable whether this is in line with the creation of a single European market.

Market shares within the national (generation) markets are shown in table 2. All in all, the share of the biggest producer remains quite high, with peaks at 85 p.c. in Belgium and France. As regards the top 3 producers, their cumulative share exceeds 60 p.c. in most countries, with the exception of the United Kingdom and the Nordic countries (considered as a whole). The benchmarking report

[23] Jamasb T. and M. Pollitt (2005).
[24] On this diversity, see for example Bergougnoux J. (2000).

from the European Commission (2003b, 2005b) emphasises that the electricity market in many Member States is dominated by one or two companies. This lack of competition would be less important if national markets were really integrated into a single European market. But the scope for cross-border trade is still inadequate for most European countries (see below). In the light of the points raised in 3.1.1, these findings should be linked to market size and efficient plant scale implying that for instance the 85 p.c. of the largest producer's market share for Belgium and for France should be seen in relation to the size of the Belgian and the French market. Whether or not there are inframarginal rents should also be analysed within the scope of the relevant market.

TABLE 2 Generation market structure
(percentage points)

	Largest producer share by capacity	Top 3 producers cumulative share by capacity
Austria	45	75
Belgium	85	95
France	85	95
Germany	30	70
Italy	55	75
Spain	40	80
United Kingdom	20	40
The Netherlands	25	65
Denmark, Finland, Sweden and Norway	15	40

Source: Commission of the European Communities (2005).

3.4 *Uncertainty, investment and security of supply*

3.4.1 Uncertainty and investment

The deregulation process has increased the uncertainty in various ways: uncertainty over sales prices, uncertainty over quantities sold and regulatory uncertainty. The uncertainty is aggravated by other events such as the internalisation of externalities (the Kyoto protocol), uncertainty over prices of primary fuels, etc.

These uncertainties might slow down investments, particularly in reserve capacities. Before deregulation, reserve capacities were considered excessive and therefore inefficient[25], but there is no guarantee that the deregulated market will optimise the reserve capacity[26]. Moreover, due to the

[25] See for example International Energy Agency (2002) or Maloney M. (2001).
[26] See for example Brunekreeft G. and T. McDaniel (2005a), L. de Vries and R. Hakvoort (2004), B. Esnault (2002), International Energy Agency (2003b), Meade R. (2005).

long lead times in power plant construction, a capacity shortage problem cannot be solved in the short term.

In addition to the unavailability of traditional market clearing mechanisms for electricity — such as delivery delay or substitution of other goods — these problems make observers worry about the outbreak of boom and bust investment cycles[27]. For instance, A. Meier (2004) from the International Energy Agency, notes that the deregulation and market liberalisation have rendered the electricity supply system more vulnerable to unusual weather events or other disruptions. The notorious Californian electricity crisis in 2001, which was caused in part by insufficient generation capacity and which resulted in a wave of blackouts throughout the State, as well as numerous shortfalls recently encountered by liberalised markets (Sweden, New Zealand, Italy, North America, ...), provide grounds for this scepticism[28]. While most markets were considered to have excess generating capacity at the time deregulation was launched in Europe, a combination of demand growth and low investments has led to a significant decrease in reserve capacities so that in most European countries new plants will be needed in the very near future in order to ensure security of supply. This is clearly apparent from UCTE (Union for the Co-ordination of Transmission of Electricity) system adequacy forecasts, which conclude among other things that:

- the period 2007-2010 shows an accelerating decline in generating capacity margins;
- at the beginning of the period 2010-2015, if no investment decisions are taken beyond those already decided on by transmission system operators, reliability of the UCTE system as a whole can be considered at risk[29].

These conclusions for the whole UCTE area have to be supplemented by a focus on the various geographical blocs, which may be connected by transmission links of limited capacity. In that case, the potential insufficiency in a country cannot be compensated by a potential surplus in neighbouring countries. In this respect, the European Commission points out (in a non-binding document) that "in the peripheral markets of Ireland, Scandinavia, Italy, Greece and the Iberian Peninsula, a trend towards capacity insufficiency is visible at times. It is conceivable that generation inadequacy will develop in the core UCTE market as well, if no adequate measures are taken."[30]

Translating the acknowledgement of an impending shortage, Directive 2003/54/EC introduced provisions specifically devoted to the security of supply issue:

27 As to the risk of boom and bust cycle in electricity, see in particular The Boston Consulting Group (2003). Booms are periods of underinvestment and rising prices and profits, followed by busts, which are periods of overinvestment and falling prices.

28 As to the California electricity crisis, see for example The Brattle Group (2001). For a list of shortfalls throughout the world, see International Energy Agency (2005).

29 See UCTE (2005). UCTE co-ordinates the interests of transmission system operators in 22 European countries, including 17 Member States of the European Union.

30 European Commission (2004).

– Member States are required to monitor the demand/supply balance on the national market, the level of expected future demand and additional capacity being planned or under construction;
– if market-based mechanisms are insufficient to avoid capacity shortages, Member States are required to cover the deficit by organising a tender[31].

3.4.2 Demand side management

The Directive also enables Member States to take measures to improve energy efficiency and demand side management. This policy area has long been neglected but, due to continuous demand growth and increased tensions on the generation side, it has attracted far more interest in recent years. The effects of demand side management measures may be summarised as in graph 5, which represents two fictitious load duration curves. The load duration curve 1 is the curve before measures, whereas the load duration curve 2 is the one after measures. The effects expected are both a shift of the curve towards the left and a reduction in the peak load demand. The first effect can notably be obtained through energy efficiency policies, such as the promotion of appliances and buildings which consume less electricity; substantial savings can, for instance, be achieved thanks to energy-saving light bulbs or improvements to stand-by modes on appliances[32]. The second effect is to be achieved by improving demand responsiveness. The aim is to increase demand elasticity by encouraging and enabling consumers to respond to market conditions. Extension of new options for electricity retail, such as real-time and day-ahead pricing or interruptible rights, have significant potential for alleviating peak-load tensions[33]. On the whole, demand side management can have a beneficial impact not only on security of supply, but also on price volatility, greenhouse gas emissions and consumers' bills.

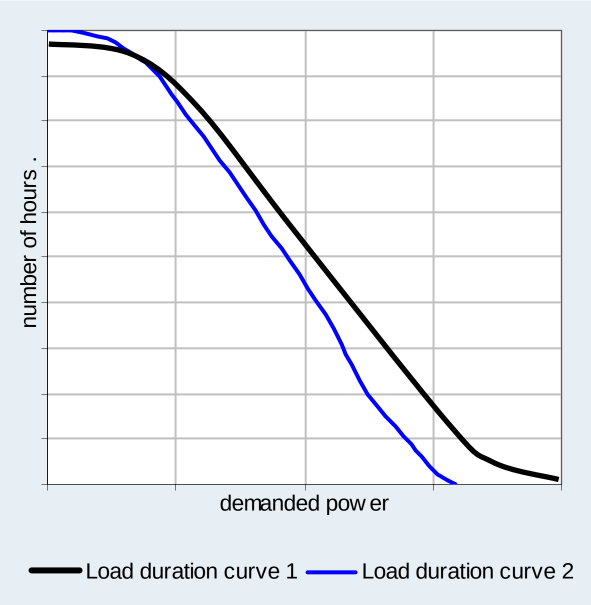
Finally, the graph shows that base-load demand may increase as a result of demand shifts, due for instance to more household appliances functioning overnight.

31 This responsibility can be delegated to the regulator.

32 See Commission of the European Communities (2005a) and International Energy Agency (2001). An energy-saving light bulb uses five times less current than a standard one. Stand-by mode electricity consumption, which accounts for 10 pct. of residential electricity demand, could be reduced by about 75 p.c. by using cost-effective technologies and design changes.

33 As to demand responsiveness, see for instance International Energy Agency (2003a), Energy SA (2001) or Turvey R. (2003). Interruptible rights pertain to the imposition of load reductions on consumers up to agreed amounts when called for, in exchange for reduced demand charges. Real-time and day-ahead pricing have already been implemented for large consumers in numerous countries. However, the situation is different for small consumers, as to which the installation of a smart meter still seems too expensive to most suppliers. One can, however, refer to EDF's Tempo tariff, in which prices vary according to days and hours. On a display unit, consumers can follow a colour indicator for the day, days being distinguished according to price (blue for low, white for medium and red for high), together with an indication of whether the hour is currently one of eight off-peak hours or not. Each evening from 8 p.m., customers can check the colour of the following day.

GRAPH 5 EXPECTED EFFECT OF DEMAND SIDE MANAGEMENT ON LOAD DURATION CURVE



3.4.3 *Primary fuels*

An issue that is closely related to the security of electricity supply - but beyond the scope of this paper - is the supply of primary fuels. It is only briefly dealt with.

Power can be generated using a diversity of primary fuels: gas, coal, nuclear, oil and renewables.

Gas turbines (CCGT) are characterised by low capital costs and relatively low CO_2 emissions. Their variable costs are high compared to their fixed costs. The primary fuel costs (the gas price) are expected to rise and to become more volatile in the future[34]. This is due to the increased demand for gas, while in the same time gas reserves will run out and become more concentrated in more faraway regions. Reserves are often compared to the current production levels through the so-called R/P ratio. The R/P ratio of natural gas reserves is 66 years[35] meaning that, at current production levels, the known reserves are sufficient for another 66 years of gas production. This assumes that current production remains constant during the next 66 years. Gas reserves are concentrated, as is seen by the fact that three countries (Russia, Iran and Qatar) hold more than half of these reserves.

Coal-fired stations have high capital costs, but relatively low and stable primary fuel costs. Coal reserves are abundant (the R/P ratio for coal reserves is more than 200 years)[35]. Their main disadvantage is the high greenhouse gas emissions.

34 See e.g. International Energy Agency (2004b).
35 See BP (2005).

Nuclear plants have very high investment costs but low variable costs. Three European countries have decided on a nuclear phase-out, namely Germany, Belgium and Sweden; other countries (e.g. France and Finland) plan to increase their use of nuclear power.
Uranium reserves are sufficient for at least 85 years of production (at current production levels)[36].

Oil is only marginally used in power generation and is also characterised by volatile and increasing prices. Currently known oil reserves will be depleted within about 40 years (at constant 2002 production levels).

Renewables have high fixed costs but negligible variable costs. They have no CO_2 emissions. Their potential often depends on climatic (wind) and/or geographical (hydro) circumstances. Fuel cells, solar, tidal and wave energy have some potential in the mid- to long-term future.

3.5 The Kyoto Protocol and its impact on the electricity sector

Reflecting the worldwide acknowledgment of the dangers of global warming, the Kyoto protocol was adopted in 1997 by member countries of the United Nations Framework Convention on Climate Change. The Protocol's major feature is that it sets mandatory targets for greenhouse gas emissions for those of the world's leading economies which have signed the Protocol. These targets range from -8 p.c. to +10 p.c. of the countries' individual 1990 emission levels. The ultimate goal is to reduce the overall emissions by at least 5 p.c. below 1990 levels in the commitment period 2008 to 2012. For almost all countries — even those set at +10 p.c; of 1990 levels — the limits call for significant reductions in projected emissions. Future mandatory targets are expected to be set for commitment periods beyond 2012. All in all, the Kyoto protocol results in assigning a monetary value to the earth's atmosphere.

With respect to the Kyoto protocol the European Union is seen as one zone, its reduction target being -8 p.c. This overall European reduction target was translated by the European Commission into national reduction targets for each Member State ranging from -28 p.c. for Luxembourg to +7 p.c. for Portugal[37]. Member States have had to establish national allocation plans assigning emission rights to individual plants in power- and heat-generating sectors and in energy-intensive industrial sectors.

Although there are noticeable variations from one country to another (due to the differences in production facilities), electricity generation accounts for a significant share of greenhouse gas emissions in the European Union, with an average of 26 p.c. of CO_2 emissions in 2002[38]. This

36 International Atomic Energy Agency (2004).
37 The US's reduction target is -7 p.c. Japan's is -6 p.c., just as Canada's. The Russian Federation has to stabilise its emissions (0 p.c.) and Australia is allowed to emit more (+8 p.c.).
38 International Energy Agency (2004a).

automatically makes electricity one of the sectors in which action has to be taken in order to meet the protocol targets. The main implication for the electricity sector is that the external costs produced by power stations emitting greenhouse gases (i.e. conventional thermal stations), are going to be internalised by producers to reflect the costs of global warming. On the electricity production side, this raises two main questions.

Firstly, green electricity has to be encouraged. In this respect, the European Union has adopted a Directive on the promotion of electricity produced from renewable energy sources[39]. This Directive sets a target of 21 p.c. for the share of green electricity in total European electricity consumption by 2010. In 2001, this share amounted to 15.2 p.c., of which four-fifths came from hydro power[40]. National indicative targets were set and, in order to achieve them, Member States have developed a variety of support schemes aiming to encourage green electricity generating plants, such as guaranteed prices, tradable green certificates or fiscal measures. In the present state of technology, wind-generated electricity is by far the most likely means of meeting the European targets.

Secondly, the Kyoto protocol puts the spotlight on the debate on nuclear electricity. In fact, nuclear electricity is a source not producing greenhouse gas emissions, so that Kyoto will not cause additional costs[41]. And, unlike wind power, nuclear power production does not depend on climatological circumstances. Some studies show how nuclear electricity might help to facilitate the achievement of the Kyoto protocol targets[42]. At this level, it should be emphasised that uncertainty or indecision is worse than a controversial decision, because such a situation may seriously hinder or divert essential investments in generating capacity[43]. A stable regulatory framework, as well as a uniform decision at the European level, would help producers to plan and optimise their production plants.

In conclusion, the dangers linked to the global warming phenomenon, and their reflection in the Kyoto protocol, put another constraint on electricity production, yielding an advantage for competitors based in countries producing intensively from green or nuclear sources. As shown in table 3, electricity producers are not equal as regards the Kyoto Protocol. The competitor with the most obvious advantage is EDF, whose carbon intensity, owing to its extensive use of nuclear and auxiliary hydro power, is very low. RWE, on the contrary, is the electricity supplier producing by far the largest volume of emissions in Europe, with a carbon intensity nearly seven times higher than that of EDF. In fact, RWE produces a significant percentage of its electricity from coal, which is the source which emits the most CO_2. Enel also has substantial emissions due to the proportion of

39 See Directive 2001/77/EC. In addition to the goal of meeting Kyoto protocol commitments, the Directive also aims at guaranteeing security of electricity supply, as green electricity is not dependent on imports.
40 Commission of the European Communities (2004).
41 The Kyoto protocol does not deal with the problem of nuclear waste.
42 See for instance Commission of the European Communities (1999). Gusbin D. and B. Hoornaert (2004).
43 For Germany, see for example Brunekreeft P. and S. Twelemann (2005).

conventional thermal power plants in its production facilities. Between these extremes there is a group composed of E.ON, Vattenfall and Electrabel, whose more balanced production facilities result in an intermediate carbon intensity. Finally, the Norwegian company Statkraft, producing exclusively from hydro power, emits no CO_2 into the atmosphere.

It should be pointed out that the figures mentioned are not an accurate reflection of the relative efforts that the companies will have to make in environmental terms, because European countries have not been assigned the same emission reduction targets. This might distort competition.

TABLE 3 CARBON INTENSITY OF MAIN COMPETITORS (2002)

Companies	**Generation (TWh) (a)**	**Emissions (thousands tCO_2) (b)**	**Carbon intensity (b) / (a)**
EDF	558	56,573	101
E.ON	191	64,160	336
RWE	183	127,046	694
Vattenfall	166	68,283	411
Enel	136	75,000	551
Electrabel	115	44,481	387
Endesa	113	59,471	528
Statkraft	49	0	0

Source: PriceWaterhouseCoopers (2003a).

4 TRANSMISSION

As pointed out in the introduction, TSOs are responsible for (1) the maintenance and development of their transmission networks as well as the interconnections with neighbouring networks, but also for (2) the operational management of their networks.

This section will focus on the cross-border transmissions from a European perspective and will therefore primarily deal with the interconnection capacities. Topics such as transmission losses, congestion management, and demand/supply balancing will also concentrate on cross-border exchanges.

This paper will try to show that electric power transport can not be compared to transport of other commodities. This is due to the fact that electricity has some very specific physical characteristics (like the occurrence of loop flows and transport losses). As a consequence, coordination of transport networks will be required but this will also have an impact on the geographical spread of the generation capacity.

The operational management of the network requires close interaction with other market participants. In a deregulated market this interaction is supposed to take place through a market mechanism, which is therefore also discussed here. Another reason for including the market mechanism in this chapter is that, in most countries, the electricity exchange is a subsidiary of the TSO.

4.1 Market mechanism - Electricity prices

4.1.1 Power exchanges

The main goal of liberalisation is to reduce and to harmonise electricity prices throughout Europe. Price movements therefore have to be carefully monitored in order to assess the effects of liberalisation. Since bilateral contract prices are confidential, prices can only be monitored through power exchanges, which have mushroomed over recent years in Europe. Although the volumes traded have increased continuously since these exchanges were created, they are still relatively small, and in most countries represent less than 10 p.c. of total electricity consumption (see table 4). The only exception is the Nordic market where around 30 p.c. of all the power consumed is traded at Nord Pool. Without underestimating the success of Nord Pool, it should be mentioned that this high figure is partly due to the fact that all cross-border power trade in the Scandinavian countries must take place at Nord Pool[44].

[44] Cross-border capacity allocation at Nord Pool makes use of so-called implicit auctioning or market-splitting (see box 4).

TABLE 4 Electricity exchanges - volumes traded on the spot market

Country	*Exchange name*	*Volume on exchange (p.c.)*
Belgium [(*)]	Belpex	-
Nordic Countries	Nord Pool - Elspot	30-40
The Netherlands	APX	10-15
France	Powernext	5
UK	UKPX	10
Germany	EEX	10

[(*)] *Planned for 2006*
Sources: APX, EEX, Powernext

Most exchanges work on a day-ahead basis. This means that any participant wishing to supply electricity the next day has to send his supply curve for each hour of the next day to the exchange authority. Every participant wishing to buy electricity has to send in his demand curve. The exchange authority aggregates all individual supply and demand curves and determines an equilibrium price for each hour of the following day. These are called the spot prices (for more details, see box 3).

Box 3: Power exchanges[45]

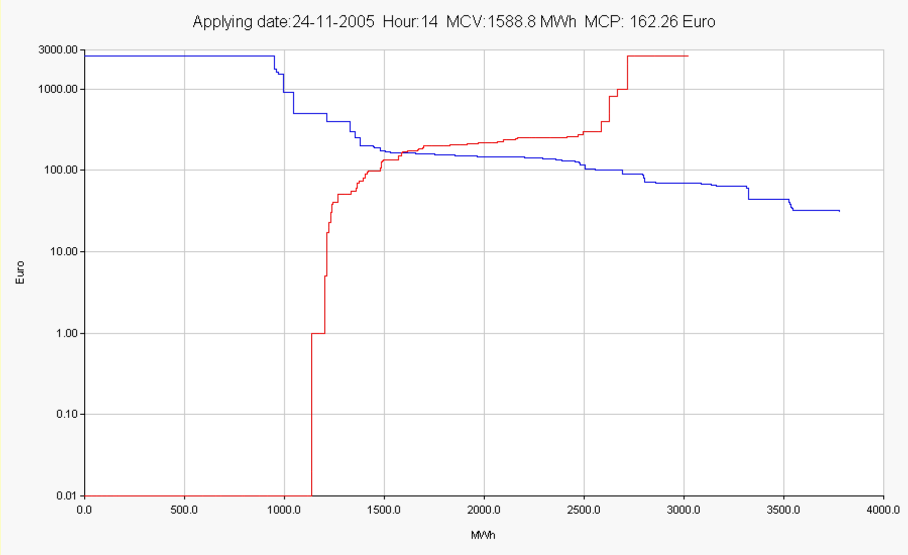
Due to the specific characteristics of electric power, power exchanges usually consist of multiple submarkets. Depending on the maturity of the exchange, some of these submarkets may be lacking.

There are markets for physical delivery (day-ahead market, fine-tuning market and balancing market) and financial markets (futures and options).

The day-ahead market mainly serves planning purposes. Before a certain closing hour L of a particular day D each producer has to submit price/quantity pairs, indicating the amount of power he intends to inject into the network at a certain price for each of the 24 hours of the following day (D+1). Likewise, buyers have to submit price/quantity pairs for each hour of (D+1), indicating the amount of power they intend to buy at that price.
After the closing hour, the power exchange aggregates all supply and demand curves and determines the equilibrium price. This yields one equilibrium price and quantity for each hour of the next day. All transactions are settled at the equilibrium price, called the system marginal price (SMP) or the market clearing price (MCP). Graph 6 provides an example from APX.

45 For details, see Coppens F., D. Vivet (2004).

GRAPH 6 Aggregated supply and demand at APX on 22.11.2005 for hour 14



Source: APX

Since the day-ahead equilibria are based on one-day-ahead expectations, and because real-time consumption and production depend on a lot of unpredictable factors (weather conditions, plant breakdown, etc.), some exchanges allow market players to fine-tune their expectations until a few hours before actual delivery. The same mechanism allows them to enter bids and offers, although their size should be relatively small. This market is called the fine-tuning market.

In real time, during the hour of actual delivery, it is the TSO that is responsible for the overall balance between supply and demand. In the case of an imbalance, the TSO has to correct. If there is excess demand, then the TSO must increase production or decrease demand. In order to do so, the TSO must use the balancing market, or sign long-term contracts with producers, or conclude interruptible contracts with consumers.

The TSO can delegate responsibility for this balancing to so-called Balance Responsible Parties (BRPs). In that case, any producer or consumer having access to the transmission network must designate a BRP. Each BRP is responsible for its own overall balance, and the TSO regulates the network balance. In other words, balancing is hierarchical. BRPs and TSO have access to the balancing market. If the TSO has to intervene, it will analyse which BRP caused the imbalance and ask for a cost compensation. BRPs having their own production plants can use these in order to insure their own balance. If they do not have their own production units, they will be exposed to the very volatile balancing market price.

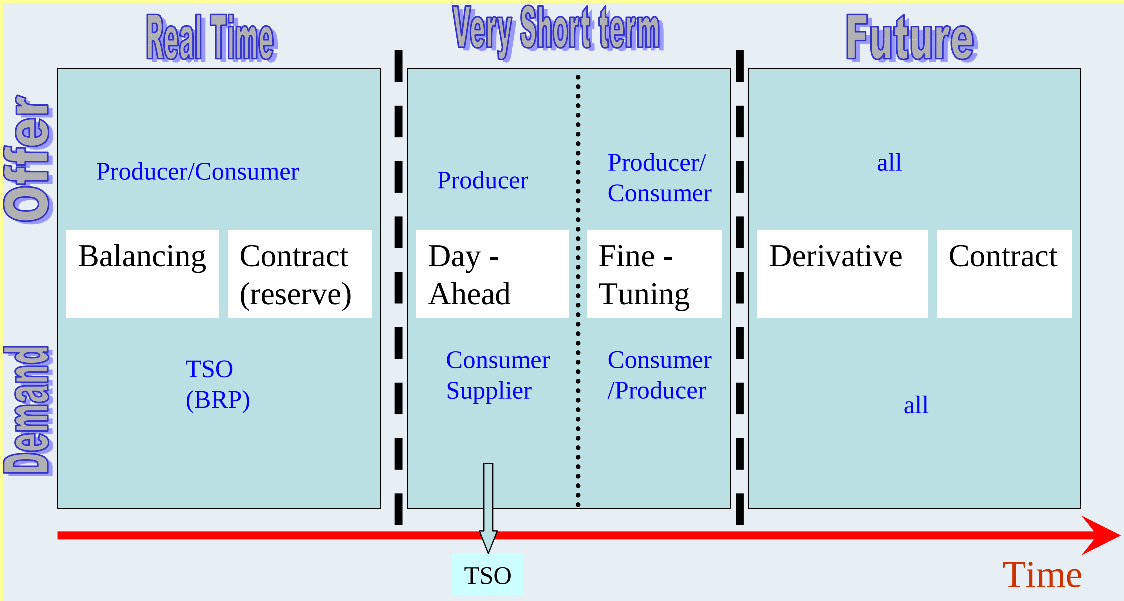
NB: power importers also have to designate a BRP.

Options and futures markets can be used to hedge against price risks, although some people doubt whether options and futures markets are appropriate for non-storable products (see Geman H.

(2002)). They argue that models for derivatives markets implicitly assume that the underlying commodity is storable. This might explain why these derivatives are more successful in the Scandinavian markets, where there are plenty of (accumulation) hydro power plants available.

All these submarkets are illustrated in figure 1.

FIGURE 1 SUBMARKETS ON A POWER EXCHANGE



In real time, producers and consumers can participate in the balancing market. They can enter bids to increase/decrease their production/consumption at a certain price.
The counterparties are the TSO and/or the Balance Responsible Parties which can, of course, also conclude contracts with producers for additional power, if needed, or conclude interruptible contracts with consumers.

Bids and offers for the near future are entered in the day-ahead (spot) market, and for the very short term in the fine tuning market. The data on the bids is accessible to the TSO in order to check for network congestion. As the prices are equilibrium prices, imbalances cannot occur.

For the longer term (from weeks to several years), producers and consumers can hedge their positions by using options and futures.

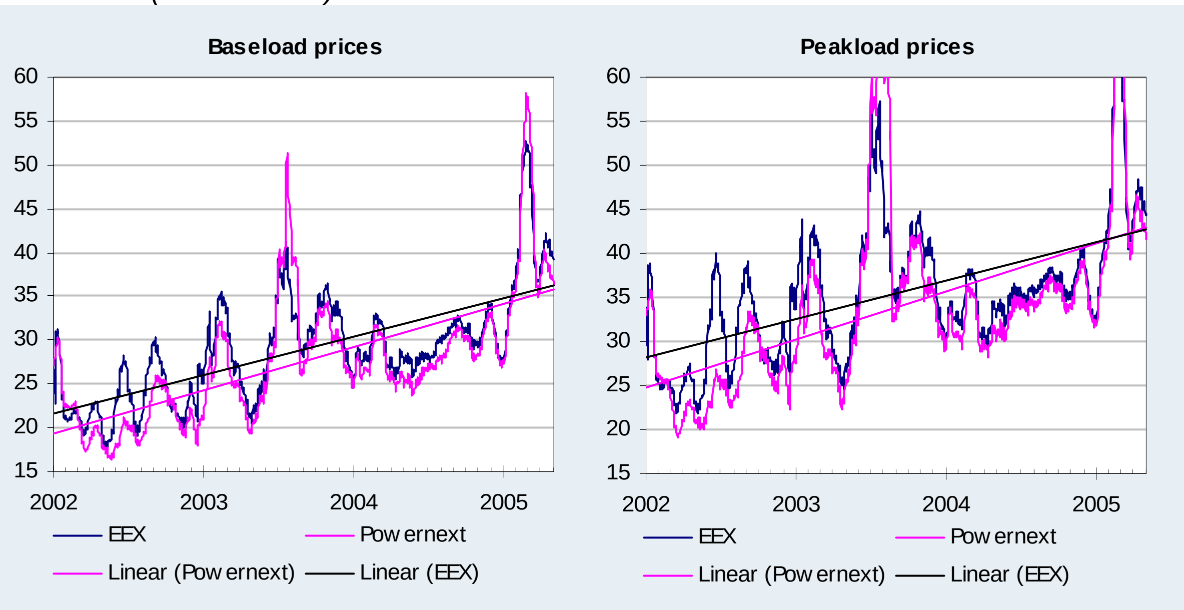
4.1.2 Electricity prices

Graph 7 shows the movement in bulk electricity spot prices on two European power exchanges: EEX (Germany) and Powernext (France). The main conclusion to be drawn from the graphs is that bulk electricity prices have tended to rise since the beginning of the millennium. There are various explanations for this increase. Firstly, oil, gas and coal prices have risen considerably in recent years, pushing up production costs. Second, the implementation of the Kyoto protocol, and the new costs associated with it, are also anticipated. These two factors are irrespective of the liberalisation process and are generally held to have a substantial impact on electricity price levels. However, since their impact cannot be quantified, it is impossible to get an idea of how prices would have moved otherwise. As such, the impact of liberalisation on prices cannot be measured precisely. Another explanation for the upward trend is related to the decline in surplus capacity (due mainly to the increasing demand) and the need for new investments, which are progressively reflected in prices, particularly during high-demand periods. This price increase may be seen as a sign that the market is functioning well, since it rightly sends a signal encouraging generators to invest in new plants. Finally, it is suggested that market power problems may lead to price manipulation but clear evidence in this respect is not available.

The graphs also show that electricity prices are very volatile with high spikes. Price volatility is an inherent characteristic of electricity prices and is a direct consequence of the volatile but inelastic demand and the non-storability of the product.

GRAPH 7 ELECTRICITY SPOT PRICES ON EEX AND POWERNEXT (MOVING AVERAGE ON 30 DAYS)

(in euros/MWh)



As far as EEX and Powernext are concerned, two main spikes can be identified, the first one occurring during the summer of 2003 and the second one during the winter of 2005. At first glance, the peak prices during the scorching hot summer of 2003 may seem surprising: in fact, even though electricity consumption was higher than normal in summer — mainly because of heavy use of air conditioning — it was still far below the winter peaks. But, as in every summer, numerous nuclear reactors were shut down for maintenance reasons. Moreover, due to the high temperature, many stations were unable to operate at full capacity because of cooling problems[46]. Lastly, the persistent drought had lowered hydro power potential. This combination of circumstances led to the highest electricity spot prices ever. As far as the March 2005 spike is concerned, it coincided with a cold spell which was abnormal in its intensity[47], its length and its period of the year. Tensions were particularly apparent on the French, Italian and Spanish markets. In France, according to André Merlin, Director of RTE (the French transmission system operator), this cold snap would not have been a problem, if it had happened in January, but in March, as every year, many plants had been shut down for maintenance and fuel reloading[48]. In addition, in order to trim demand peaks, EDF had contracted interruptible rights during the winter on about 800,000 customers. But, as such, a late cold snap was exceptional, 19 of the 22 contractual days had already been used up by the end of February, so that this additional tool was not available to curb the peak demand in March. As a consequence, electricity had to be imported from Germany and Spain during this period. On EEX, whereas supply was sufficient to cover demand, prices increased by contagion.

In conclusion, one can see that electricity prices are strongly influenced by factors irrespective of liberalisation. On the one hand, primary energy costs and Kyoto protocol rules have pushed prices upwards for several years. On the other hand, climatic constraints are a permanent threat to the electricity system, which in some cases responds with high price volatility due to the low demand elasticity. It is crucial to note that climatic conditions have such an impact because of electricity-specific characteristics which, as emphasised above, make the traditional market clearing mechanisms (such as delivery delay and substitution of other goods) unavailable.

4.1.3 Congestion management

Since interconnection capacities are constrained (see paragraph 4.3 infra), cross-border exchanges have to be managed in order both to maximise competition and to avoid system overload. This topic is considered in the European Regulation 1228/2003 ("on conditions for access to the network for cross-border exchanges in electricity"), which states that network congestion problems must be addressed with non-discriminatory and market-based solutions. Currently, a wide range of congestion management methods are used across Europe[49]. In continental Europe, the most used method is explicit auctioning, while market splitting/coupling, initially only used in Scandinavia, should expand considerably with the decision taken recently by the Belgian, Dutch and French power exchanges to link their markets to integrate their exchanges (APX, Powernext and Belpex) and to use this technique to allocate (part of) the cross-border capacity.

46 Faced with the crisis, the French government authorised power stations to discharge water at a higher temperature than normally permitted. As to the measures taken in France to manage the crisis, see for example Mattatia S. (2003).
47 With, for example, temperatures 10°C below the average for the time of the year in France and Spain.
48 Le Monde, the March 11, 2005.
49 As can be seen for instance in ETSO (2004).

Under explicit auctioning, the TSOs of the systems between which congestion exists sell their interconnector capacity to the highest bidder; explicit auctioning thus separates transactions in electricity from transactions in cross-border transmission capacity.

Market splitting, also called implicit auctioning, integrates electricity and transmission markets. The existence of a power exchange on each side of the interconnector is a necessary condition. Market splitting is today generally regarded as the most efficient and transparent congestion management method[50]. Box 4 focuses on how it operates in theory. Ultimately, explicit auctioning and market splitting generate incomes that are supposed to reflect the marginal value of the congested interconnector[51].

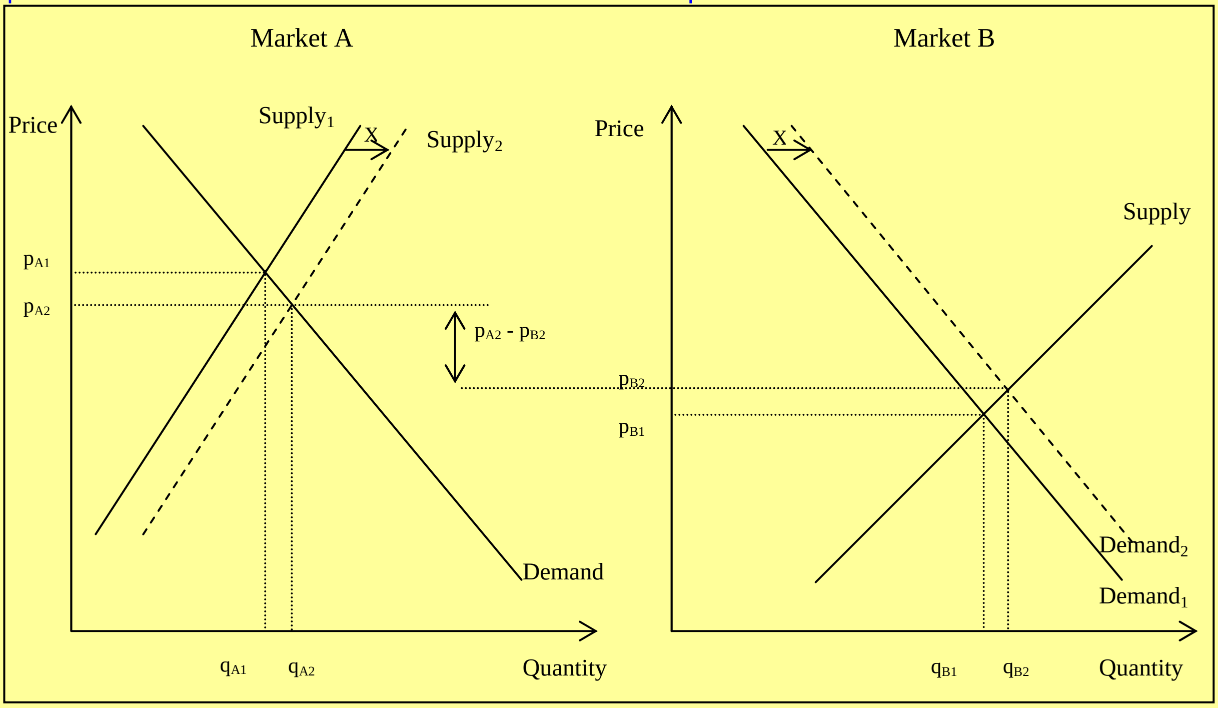
Box 4: Congestion management : market splitting

Graph 8 describes the market splitting mechanism in a simple theoretical case of two countries with limited interconnection capacity. At a first stage, each country's spot market clears as if there was no interconnection between them. The initial equilibria are (q_{A1},p_{A1}) on market A and (q_{B1},p_{B1}) on market B. Then the market operator of the market with the highest price, i.e. market A, buys electricity from the exchange with the lower price, i.e. market B. The amount of electricity imported is just as high as the congested line allows, and is equal to quantity x. On market A, electricity imports mean a supply increase, so that the supply curve shifts to the right. The movement is exactly the opposite on market B, where exports imply a demand increase and a shift to the right. This results in two new equilibria, i.e. (q_{A2},p_{A2}) and (q_{B2},p_{B2}), corresponding to a price decrease on market A and a price increase on market B.

50 It is also supported by the European Commission (2001b).
51 For an overview of congestion management methods, see for instance Boisseleau F. and L. de Vries (2001) or Krause T. (2005).

GRAPH 8 MARKET SPLITTING MECHANISM

Spot market A Spot market B



For each unit of electricity imported/exported, the market operators have thus received a margin equal to the price gap, i.e. p_{A2}-p_{B2}, so that their total profit is (p_{A2}-p_{B2})*x. The unitary margin reflects the marginal value of the congested interconnector. It may also be noted that, on the whole, society has benefited, since the aggregate surplus for society (i.e. the sum of aggregate producer and consumer surplus) has increased in both markets.

Summing up, if the interconnector is not congested, both zones have the same price. If the interconnector is congested, the prices in the two zones will be different. It follows from the reasoning above that the market splitting mechanism requires a power exchange at both ends of the interconnector.

4.2 The physics of electricity transmission

Since electricity generation and power consumption take seldom place at the same location (this is due to specific needs of generation equipment, like cooling water, to the difference in size of production and consumption units, ...) electrical power transport is required. Such transport makes use of high voltage lines because high voltages limit transport losses[52]. But even in that case losses can be substantial[53]. Without entering into technical details one can say that there are two alternatives for transporting power; (1) high-voltage direct current (HVDC) power transport and (2)

52 See also Coppens F., D. Vivet (2004).

53 It can easily be computed that, typically, o*n a 380 kV line the power lost is around 0.5 p.c. per 100 km under normal circumstances (i.e. with a 50 p.c.load factor) Thus if 500 MW is transported over a 1000 MW* line, *every 100 km around 2.5 MW is dissipated as heat.*

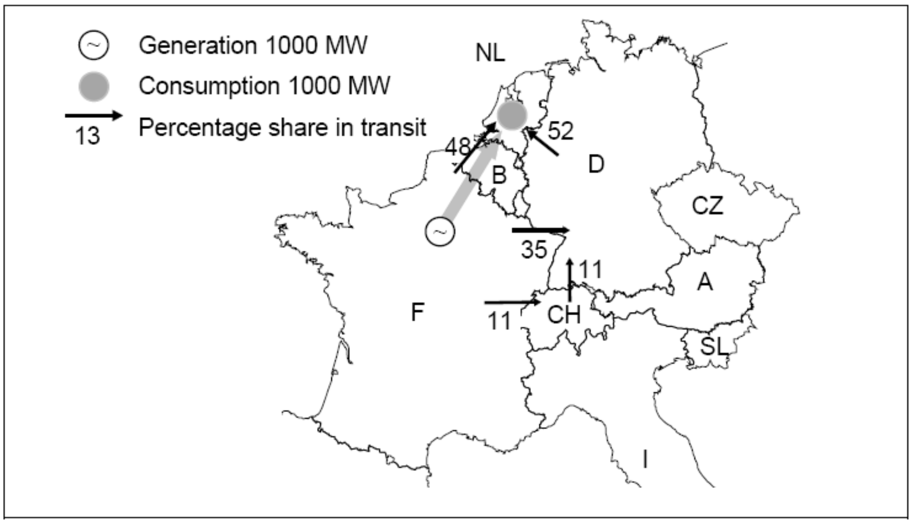
high-voltage alternating current (HVAC) transport. HVDC transport shows lower losses and lower transport infrastructure costs (pylons and cables) than HVAC transport, however, since most user equipment and most generating equipment uses (resp generates) alternate current, an HVDC system requires (very expensive) conversion equipment. It follows that such HVDC transport is only advantageous when power has to be transported over very long distances without being tapped underway (i.e. for peer to peer transport). This is why most of the contemporary power transport uses HVAC lines. Only in exceptional cases (undersea power transport, power generated from hydro stations in the north of Sweden is transported to the south through HVDC lines) HVDC is used.

For reasons of security of supply these HVAC transport networks are meshed giving rise to the problem of so-called loop flows. Physical laws (i.e. the laws of Kirchhoff) imply that electrical current follows the path of least resistance, so that power flowing through a meshed network follows a non-deterministic route. This implies that when a consumer and a generator contract for the delivery of a certain amount of power at a certain time of delivery, the consumer can never be sure that the power he consumes comes from the generator he contracted with. This is in strong contrast to the transport of other commodities and has some complex side effects.

Figure 2 shows the flows generated by power sales from a French producer to a Dutch consumer. In that case only 48 p.c. of the power sold transits through Belgium, the remainder is transmitted via Germany and even Switzerland. In a similar way, sales from a French producer to a German consumer cause substantial unidentified flows (also called loop flows) via Belgium[54].

[54] 34 p.c. transits through Belgium and the Netherlands, 35 p.c. crosses the French-German border immediately, 18 p.c. is transmitted via Switzerland and 13 p.c. flows through Italy (source RTE).

FIGURE 2 LOOP FLOWS GENERATED BY POWER SALES FROM A FRENCH PRODUCER TO A DUTCH CONSUMER.



Source: Haubrich H.J., Fritz W. (1999).

Thus, a transaction between a French generator and a Dutch consumer entails unidentified flows in the transmission network of several TSO's and in the interconnectors, potentially creating congestion on some of the transmission lines. TSOs must manage these flows. It is evident that this loop flow management requires a lot of coordination among TSOs. The associated costs are transport costs. These costs can however not be charged to the contracting parties.

The loop flow problem interacts with other difficulties associated with electrical power. A relatively clear example is the volatility of wind power production. Wind power plants are 'must run' units - i.e. they should produce when there is wind - their production is unpredictable. The 'must run' property implies that all at a sudden the injection of wind power in the network can increase significantly, causing loop flows on neighbouring lines and networks. As such, supplies from a wind-based power plant in the north of Germany to a large consuming center in the south of the country induce loop flows through the Netherlands, Belgium and France.

The undetermined transport path, combined with the phenomenon of transport losses entails other side effects and costs. Indeed, assuming that an Italian consumer concludes a contract with a Danish producer for the delivery of 100 MW of electrical power in a particular hour, then the Italian consumer will extract this 100 MW and the Danish generator will inject it during that specific hour. However, due to the meshed European grid and to the laws of Kirchoff, the Italian consumer will not receive Danish power but part of it will come from neighbouring generators. Some power will also be lost due to heat dissipation underway and these losses will have to be compensated by different European TSOs by injecting additional power (bought on the balancing market, see box 3). This loss compensation however entails costs for these TSOs. These costs can not be charged to any individual consumer of producer (because the consumer/producer can not be identified) so that these costs will have to be compensated out of a common fund (see box 5 for additional information on the ETSO cross-border trading mechanism)[55] [56].

Box 5: The ETSO cross-border trading (CBT) mechanism

When a generator and a consumer, located in different regions, contract for the delivery of electrical power, the physical characteristics of electricity transport imply that transport costs (the management of loop flows and the compensation of transport losses) can not be charged to the parties involved in the transaction. As a consequence, the intermediate TSOs incur costs which they should be compensated for. The financial compensation of these costs occurs through the cross-border trading (CBT) mechanism. The entities involved in this CBT mechanism are the participating TSOs. Some TSOs (i.e. the TSOs where the generator and the consumer are located) will have to contribute to a common fund, others (the TSOs that have to compensate losses and to manage loop flows) will have be compensated for the incurred costs.

In order to finance the CBT costs, every TSO that participates in the CBT-mechanism contributes to a compensation fund in proportion to the size of its net imports or exports. Thus TSOs having high net imports (or exports) contribute more to the fund than smaller (net) importers (exporters)[(*)].

The amount due to each TSO (for managing loop flows and for loss compensation) consists of two components - a transit component (including loop flows) and a loss component. The transit component equals the fraction of transits on its network multiplied by the long-run average costs (LRAC) of its network (i.e. $\frac{transits}{transits + total\ load} \times LRAC$), the first factor is called the 'transit key'. The loss component equals the total losses on the transits times the average energy price.

According to the reasoning above, all participating net importers or exporters contribute to the CBT compensation fund. However no contributions are paid for imports coming from non-participating TSOs (note that exports to non-participating TSOs are included)

For each import into a participating country, coming from a non-participating country (called a perimeter country), a fee of 1 €/MWh is charged to the perimeter country. These fees also contribute to the financing of the CBT mechanism.

(*) *These contributions can be included in the access tariffs charged by the TSO to its local users (i.e. generators and consumers).*

55 For an example of the difficulties encountered in such common compensation mechanisms, see for instance. Daxhelet O., Y. Smeers (2005).

56 It should be mentioned that there are also losses on loop flows.

The fact that each intermediate TSO compensates part of the losses implies that power is never transported over very long distances and losses are relatively limited. However these losses are only limited when there are neighbouring generators in order to limit the transport distance to be covered. The condition, thus, is that power generation is dispersed across Europe. This means that, unlike for other commodities (e.g. steel), a situation in which all power is generated in a certain region (due to competitive advantages) and then transported over long distances to a consuming region, is inconceivable.

It is also worth mentioning that power transport infrastructure is capital-intensive and is characterised by high construction lead times. The environmental and aesthetic problems associated with power transport give rise to NIMBY attitudes further increasing lead times. It is clear that this problem is even worse for interconnections between member states.

4.3 Interconnection infrastructures

For several years, numerous documents from the European Commission have been underlining the insufficiency of interconnection capacities between Member States, which is crippling the creation of an integrated European electricity market[57]. In particular, more interconnection capacity would do much to correct the problems associated with the national market structures, which are too often concentrated (see 3.1.1), by allowing competing imports from abroad. Increasing interconnection capacities is also a way to improve security of supply.

Due to the limited interconnections, Europe is far from being a totally integrated market. In fact, the European electricity system should rather be seen as consisting of a core area (Germany, France, the Netherlands, Benelux, Austria and Switzerland) and satellites with limited interconnection capacity, such as Ireland, the United Kingdom, Scandinavian countries and the Iberian peninsula. Even though interconnections between these blocs can be improved, long-distance exchanges may not be seen as an objective in themselves, due to network losses (see 4.2). That is why UCTE, the Union for the Co-ordination of the Transmission of Electricity, taking a long-term view, claims that a competitive European market is a market where supply is competitive on a local level[58].

Table 5 presents the level of interconnection capacity for a number of countries, by "electric region". The main conclusion to be drawn is that the biggest producing countries have (very) few interconnections with the others. Moreover, a lack of interconnections can be observed both between the regions and within them. For example, because of substantial exports from France to the Netherlands and Germany, the interconnector on Belgium’s southern border is congested most

57 See for example Commission of the European Communities (2003a).
58 UCTE (2003).

of the time, despite Belgium's apparently satisfactory level of interconnections. Moreover, import capacities in table 5 do not take into account the existence of long-term contracts concluded before the liberalisation process started. In some cases, these contracts monopolise a significant proportion of the interconnections, which as a consequence are unavailable for competition. Conversely, the Scandinavian markets are generally considered to be well integrated with each other[59].

TABLE 5 INTERCONNECTION CAPACITIES

	Import capacity as a percentage of installed capacity (pct.)
Belgium	29
France	13
Germany	11
Luxembourg	90
The Netherlands	17
Austria	24
Italy	8
Portugal	8
Spain	4
United Kingdom	3
Ireland	6
Norway	18
Sweden	29
Denmark	50
Finland	14

Source: Commission of the European Communities (2005).

The European Commission has taken a number of initiatives in order to improve this problematic situation. In particular, several critical bottlenecks have been identified, where investments are a priority and are supported financially. In this respect, reference can be made to the interconnections between France, Germany and Benelux, between France and Spain, between Denmark and Germany, between Italy and all its neighbouring countries, and between the United Kingdom and continental Europe. The interconnector capacities have already improved, but it will take quite a long time to realise the necessary investments. Another notable initiative was launched at the

59 On the integration of Scandinavian markets, see for example Bergman L. (2003).

European Council of Barcelona, which set the target for Member States to have a level of electricity interconnection equivalent to at least 10 p.c. of installed production capacity by 2005. Even though it is difficult to determine the optimum level needed precisely, it is clear that this target will not suffice, in particular for countries where the market is still highly concentrated.

As regards the interconnections issue, the European Commission has recently emphasised the importance of developing regional markets as a necessary intermediate stage on the road to a European market[60]. These regional markets would be composed of Member States with a reasonably good level of interconnection; in the Commission's view, these markets include the Iberian market (Portugal and Spain), the West European market (Austria, Belgium, France, Germany, Switzerland and the Netherlands), the Italian market and the Nordic market (Denmark, Finland, Norway and Sweden). The Commission expects these markets to develop a more harmonised regulatory approach, in particular as to the degree of market opening, the setting of transmission tariffs or congestion management. The Commission leaves the initiative to the Member States and expects the regional markets to develop "organically" through cooperation between institutions in neighbouring countries[61].

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60 See European Commission (2004b), and ERGEG press release PR-06-05 of 27 February 2006.

61 However, it may be held that a European legal framework for regional markets should be developed with a set of minimum requirements. This would certainly speed up the creation of the regional markets and facilitate their integration into a single European market. On the regional markets issue, see for instance de Jong J. (2004).

5 REGULATION

The term "regulation" covers a wide range of areas, such as the tasks assigned to the sectoral regulatory authorities, the legislative package, the market design or the overall regulatory context in which liberalisation takes place.

As far as regulatory authorities are concerned, the duties assigned to them by Directive 2003/54/EC are essentially of a technical nature. Their key task is the approval of network access tariffs and conditions. Methodologies for tariff setting are to be approved in advance, but changes can be required on an ex post basis. The regulator must also monitor and in the event of problems concerning, among other things, the management of interconnection capacities, the management of congested national systems, the unbundling of accounts or the connection of new producers and act if necessary. Regarding any of these issues, the regulator has to settle complaints against the transmission or distribution system operator.

Essentially on the initiative of the European Commission, national regulators meet in several organisations, such as the Electricity Regulatory Forum of Florence, (better known as the Florence Forum), the CEER (Council of European Energy Regulators) or the ERGEG (European Regulators Group for Electricity and Gas)[62]. They share the same objective, i.e. the building of a European energy market. Although praiseworthy in terms of their cooperation and their role in offering advice and exchanging expertise, these meetings are only of a consultative nature, so that their effectiveness strictly depends on the Member States' degree of consensus.

As far as the overall regulatory context is concerned, there are two main issues, namely regulatory uncertainty and inadequate harmonisation. In the case of electricity, the uncertainty concerns various aspects and may roughly be divided into two elements. The first source of uncertainty is the liberalisation process itself, which, through its various adjustments and related controversies, certainly does not inspire confidence among enterprises. The process has been largely evolutionary and most stakeholders expect it to go on evolving. The second source of uncertainty is constituted by issues surrounding the sector, such as the debates over nuclear energy, the enforcement of the Kyoto protocol and its effects, which are difficult to predict, as well as the possible interference of

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62 Created by the Commission in 1998, the Florence Forum convenes twice a year and brings together the Commission, national electricity regulators and responsible ministries, TSOs, industry and consumers. The goal of the Forum is to discuss issues that are not addressed in the Electricity Directive relating to the creation of a real internal electricity market. The main issues addressed by the Forum concern the tarification of cross-border electricity exchanges and the allocation and management of scarce interconnection capacity.
The CEER was created in 2000 as an association of national regulators, and has two objectives, namely mutual cooperation among regulators and cooperation with the European institutions. The ERGEG was established by the European Commission in 2003 and aims at facilitating consultation, coordination and cooperation among national regulators, as well as fostering the consistent application of European Directives and any future legislation. CEER and ERGEG share similar objectives and they are closely linked.

political interests[63]. As highlighted above, these factors may have harmful consequences such as hindering or diverting essential investments.

As regards harmonisation problems, it should be recalled that the EU decision-making process is consensus-oriented and that this tends to lead to insufficient outcomes for those policy areas where a broad consensus is missing[64]. This is indeed the very case for electricity deregulation, which has been particularly subject to controversy between Member States, as reflected by the long period of bargaining before an agreement was reached on the first Directive. In accordance with the subsidiarity principle, this first Directive left many options open for national implementation and was subject to sometimes acid criticism such as that by Hancher (1997): "The margin of choice [given by the Directive] is so substantial that it would seem possible for determined anti-market countries to avoid introducing any meaningful degree of competition at all." Nearly ten years after the beginning of the deregulation process, in view of the divergences in market concentration, market interconnections and the degree of unbundling between countries, such a judgement deserves credibility. Yet, the second Directive as well as Regulation 1228/2003 have reduced national margins of choice to some extent, notably in the fields of network access and cross-border exchange management. In particular, Regulation 1228/2003 authorises the European Commission to establish guidelines on cross-border trade, under what is called the "comitology procedure"[65]. However, on aspects such as security of supply or public service obligations, although the objectives are set, the tools to be used are largely left to the Member States' discretion. Another factor of distortion is the absence of any uniform decision on the nuclear question, which automatically favours the generators based in countries where the technology is allowed.

More generally, electricity market design, particularly the ways in which competition is introduced and market power problems are handled, is still greatly affected by the lack of harmonisation. On the resolution of currently unsolvable market power problems, it might be interesting to refer to a passage from the Belgian regulator’s annual report, in response to a study calling for the divestment of Electrabel, the dominant Belgian generator: "*Ultimately, the policy adopted by the European Union should ensure the emergence of a European electricity market instead of the various national markets. The players on the European market could be limited in size and extremely numerous. (...) Equally, however, the market could consist of a few very large groups (...). The form which the*

63 These political interests may be very diversified, with for instance the desire to guarantee self-sufficiency in energy, to cap prices if they become too volatile or to defend a national supplier. As to this last point, an example which may be referred to is law 301 passed by the Italian Government in 2001, better known as the "anti-EDF law", after EDF had bought about 20 pct. of the Italian company Montedison. The law imposed a 2 pct. cap on a shareholder's voting rights in an Italian electricity or gas company, if this shareholder was a public company in a dominant position on its national market and not quoted on a stock exchange.

64 See Egenhofer C. and K. Gialoglou (2004).

65 For a description, see for instance de Jong H. and R. Hakvoort (2005). Under the comitology procedure, the Commission chairs a regulatory committee composed of the representatives of the Member States and, in the case of electricity regulation, also of the ERGEG, acting as an advisory committee. These committees enable the Commission to set up a dialogue with national administrations before adopting certain measures. For a guideline to be adopted, it must be approved by a qualified majority within the regulatory committee.

market of tomorrow will take will basically depend on the policy implemented by the states in which the main electricity companies are currently established. However, none of these states has so far taken effective steps designed to create perfect competition at European level. Belgium does not fall into this category of states, and so does not take part in this decision-making process. This is also why the abolition of a dominant position on the Belgian electricity market would not have any effect. On the other hand, Belgium can make its weight felt as it has a medium-sized enterprise at European level. It is precisely the existence of this type of enterprise that will make it possible to prevent the big groups from abusing their dominant position on the market without restraint, to the detriment of consumers."[66] This passage most aptly illustrates and highlights how the lack of market design uniformity inhibits the tackling of market concentration at national level.

[66] Foreword by the chairman in the Commission for Electricity and Gas Regulation (2004).

6 CONCLUSION

Electricity liberalisation in Europe is part of the wider trend towards the deregulation of network industries around the world. Whereas empirical evidence generally suggests that deregulation has had a positive impact on efficiency and consumer welfare in telecommunications and air travel for example[67], the results expected for the electricity sector are much more ambiguous so far. Anyway, as only a few countries have fully completed their deregulation process, the available evidence is not yet sufficient to build a comprehensive judgement. Moreover, as far as the European Union is more particularly concerned, factors external to the deregulation process in the strict sense cause interference. For instance, increasing oil, gas and coal prices as well as the enforcement of the Kyoto protocol are responsible for much of the increase in bulk electricity prices, but, as that impact cannot be quantified, it is also impossible to determine how prices would have moved otherwise, i.e. the real impact of deregulation. Nevertheless, as was done throughout this paper, one can point out a number of issues raised by electricity deregulation, which could influence the final outcome.

The foremost problems are related to the unusual characteristics of "electricity" as a product, which make the industry very different from other network industries: electricity is not storable, demand and supply must be constantly balanced, and demand is both volatile and inelastic. As a consequence, the traditional market clearing mechanisms, such as delivery delay or substitution of other goods, are not available for electricity. This implies price volatility on power exchanges and makes the security of the system more vulnerable to climatic conditions. It also creates the need for a heterogeneous production park with sufficient reserve generation capacity. This virtually divides the generation market into base-load, mid-peak and peak-load segments. This in turn might give rise to economies of scale in some subsegments and the existence of inframarginal rents and as such create entry barriers hindering competition.

Although there is an economic rationale for the choice for heterogeneous generation technologies, today's heterogeneity in generation mix across European countries has been dictated by past national choices based on a combination of economic, geographical, geopolitical and/or political considerations. Nevertheless this mix has important consequences in deregulated markets: generators based in countries where the least costly techniques (i.e. nuclear and hydro power) are available enjoy an ex nihilo competitive advantage. This advantage is further strengthened when greenhouse gas emissions are internalised.

In order to avoid a system breakdown, efficient coordination and the exchange of information are required between the various segments of the sector — i.e. generation, transmission, distribution

[67] See Gönenç R., M. Maher and G. Nicoletti (2001).

and supply. The unbundling of these segments, which is one of the central measures in the deregulation process, has complicated the achievement of this crucial requirement and entails a new type of costs - transaction costs - that might reduce the potential gains from the introduction of competition in generation and supply.

As far as interconnection capacities between national markets are concerned, they are widely considered as insufficient. This situation is crippling the creation of a single European market. More interconnection capacities would in many cases solve the problem of concentration on national markets. The European Commission has taken initiatives to improve this situation, such as financial support for investments where critical bottlenecks exist. Since it will take a long time for these investments to realise, the Commission has recently emphasised the benefits of developing regional markets as an interim stage on the road to a European market. In practice, with the exception of Nord Pool, national markets are still far from being integrated. Regional integration initiatives are, however, emerging, such as the recent decision to couple the Belgian, French and Dutch markets.

As far as international power trade is concerned, it should be mentioned that power transport over long distances requires high infrastructure investments and is characterised by high operational costs (compensation of losses, congestion management, loop flow management etc.). As a consequence - costs being the sum of generation and transport costs - power generation will probably always be dispersed across Europe

The electricity industry is also at the crossroads of two important concerns, i.e. the enforcement of the Kyoto protocol and the security of the energy supply. Whereas pollution and security problems were previously considered as market failures and, as such, were managed by governments through industry regulation and planning, the present European policymakers tend to prioritise the market as the way to solve them. However, this market approach is not free from criticism. For instance, the unequal national reduction targets and the use of different technologies, combined with the existence of entry barriers, might distort competition. As far as security of supply is concerned, there are a number of reasons why the market by itself might not be able to achieve a satisfactory level of reserve capacity as well as an appropriate diversity in the mix of fuels used by the electricity-generating facilities.

In order to minimise the impact of these difficulties on the deregulation outcome, a consistent regulatory framework is essential. However, the current framework seems far from satisfactory.

Firstly, the current regulatory framework creates uncertainty. The first source of uncertainty is the liberalisation process itself, which, through its various adjustments and related controversies, certainly does not inspire confidence among market players. The process has been largely evolutionary and most stakeholders expect it to go on evolving. The second source of uncertainty concerns issues surrounding the sector, such as the debates over nuclear energy, the enforcement of the Kyoto protocol and its effects on prices which are hard to predict. These factors of uncertainty may have harmful consequences such as hindering or diverting essential investments.

Secondly, the regulatory framework suffers from a lack of harmonisation. This is mainly due to the EU decision-making process, which is in general consensus-oriented, and which therefore tends to lead to minimalist outcomes for those policy areas where a broad consensus is missing. Now this is precisely the case for electricity deregulation, which has been and still is particularly subject to controversy between Member States. This situation has resulted in extensive freedom in terms of national implementation. The lack of harmonisation is particularly prejudicial to the economic design of the market, notably the degree of competition introduced, the handling of market power problems, the decisions concerning interconnections, the degree of unbundling or the ways of ensuring adequate investment. A last point is the absence of a unified decision on the nuclear question, which would eliminate a source of competition distortions.

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